RENEWABLE NORTHWEST PROJECT

UM 1610

REPLY TESTIMONY OF

JIMMY LINDSAY

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON

Staff Investigation Into Qualifying Facility Contracting and Pricing

April 29, 2013

INTRODUCTION

Q. Are you the same Jimmy Lindsay who previously submitted testimony in this proceeding on behalf of Renewable Northwest Project ("RNP")?

A. Yes.

Q. What is the primary purpose of your reply testimony?

A. My reply testimony primarily addresses the Oregon Public Utility Commission ("Commission") Staff's response testimony. In that testimony, Staff supported retaining the 10 MW published rate/standard contract threshold for Oregon's implementation of the Public Utilities Regulatory Policy Act of 1978 ("PURPA") only if avoided cost rates are adjusted by generic capacity value factors assigned to qualifying facilities ("QFs") according to their generating technologies. While I support retaining the 10 MW threshold, I do not recommend that the Commission approve Staff's concept unless it also takes two additional steps: (1) requires utilities to incorporate a measure of resource capacity value that accounts for annual contributions to system reliability; and (2) balances the Staff-proposed capacity value adjustment, which recognizes the capacity value advantage of the gas proxy, with recognition of several other intervenor-proposed adjustments that recognize distributed, renewable resources' portfolio advantages over centralized and fossil-fueled resources (*e.g.*, value of deferring large investments in generation, avoiding natural gas infrastructure costs).

Q. Do you address any other issues in your reply testimony?

A. Yes. I address other parties' testimony concerning integration costs for QFs, transmission costs of the proxy resource, line loss adders for distributed resources, definition of renewable energy credits ("RECs"), and refinements to the five-mile stipulation.

CAPACITY VALUE DETERMINATION

Q. Does Staff's testimony propose a method for determining the resource capacity value by which the avoided cost rate would be adjusted?

A. Not really. Staff's testimony proposes that each utility use a specific capacity contribution value for each resource type. Staff describes this "capacity contribution factor" as the "expected contribution to peak load of the specific QF resource type" but does not recommend a specific methodology to calculate the capacity value of each resource type. *See* Staff/100/Bless/23.

Q. How have the utilities generally proposed to determine capacity value?

A. In this proceeding, PacifiCorp has calculated the capacity contribution of wind and solar resources using the exceedance method. PacifiCorp's application of the exceedance method identifies the level of solar and wind generation which is exceeded during 90 percent of the 100 highest summer load hours. *See* PAC/100/Dickman/14. Idaho Power has calculated the capacity contribution of hydro, canal-drop hydro, wind and solar using an exceedance method for the on-peak hours in the month of July. *See* Idaho Power/200/Stokes/27. PGE did not propose a capacity value methodology, yet does distinguish between variable energy resources and baseload resources. *See* PGE/100/Macfarlane – Morton/15.

Q. Does the exceedance methodology have any significant weaknesses?

A. Yes. The exceedance method has two significant weaknesses. First, the exceedance method only considers contributions to reliability for a short time period often associated with hours of peak demand. The methodology does not capture contributions to meet load outside this narrow time period, even if a resource delivers capacity when the system is similarly stressed—for example, in the event of low hydro flows or an outage. Loss of load probability ("LOLP") studies and energy not served ("ENS") calculations demonstrate that utility power systems frequently are unable to meet system demands at times outside the highest peak load hours. All resources, including solar and wind, reduce annual LOLP/ENS by making real and measurable contributions to system reliability. The exceedance method does not recognize the full capacity value that resources provide.

Second, the exceedance method relies on an arbitrary assumption that greatly affects the method's results. The method measures the generation level that a particular resource or resource class exceeds during a predefined percentage of certain predefined hours. For example, PacifiCorp's methodology measures the level of wind generation that is available during 90% of the 100 highest summer load hours. *See* PAC/100/Dickman/14. As described above, the selected time period is an anecdotal window that is related to, but not equal to, the utility's capacity constrained hours. The selected percentage of availability during that window (90% in the case of PacifCorp) is also an arbitrary choice. No resource is available 100% of the time and a 50% exceedance level is equal to the arithmetic average. Between those bookends, a utility must make an arbitrary selection. Variable generation availability at different exceedance levels does not scale in a linear fashion, meaning that small differences in the assumed exceedance level can produce a large difference in the result. Idaho Power's methodology is equivalent to a 50% exceedance level (*see* Idaho Power/200/Stokes/27), the California Public Utility Commission has assumed a 70% level with a diversity adder,[1] and PacifiCorp is employing a 90% exceedance level. None of the assumed levels are more or less correct than another, and this dramatically undermines the consistency and reasonableness of the method.

Q. Did any other party propose a superior method for determining resource capacity value?

A. Yes. ODOE recommended that utilities use the effective load carrying capability ("ELCC") method for measuring the capacity value of resources. The ELCC method is well supported by utility practice. The North American Electric Reliability Corporation ("NERC") recommends that the capacity value of variable generation be measured using the ELCC method. The IEEE Power and Energy Society considers the ELCC method the best practice for measuring intermittent generators' capacity value. The Northwest Power and Conservation Council,

[1] California Public Utilities Commission, Rulemaking 08-01-025, Decision 09-06-028 (June 22, 2009), Appendix C, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/102755.PDF.

[2] NorthWestern Energy's Schedule No. QF-1, 2nd Revised Sheet No. 74.6 (available at http://psc.mt.gov/Docs/ElectronicDocuments/pdfFiles/D2012-1-3IN13011054131TA.PDF) specifically states:

"Wind Integration: Sellers of Wind Energy selecting Options 1 or 2 must contractually agree to the through its Resource Adequacy Forum, has also identified and used the ELCC method to determine wind generators' capacity value.

Q. How does the ELCC methodology work?

A. The amount of additional load that a resource enables the system to serve with equal system reliability is a resource's ELCC. Generators that are consistently available during peak demand have a high ELCC. Generators that are consistently unavailable during peak demand have a low ELCC. Therefore, the ELCC method is useful for planning to meet peak demand. However, the ELCC method also credits generators for their deliveries during forced and scheduled outages elsewhere on the power system. In other words, the ELCC method evaluates any resource's contribution to reliability over all hours of the year. Adding generation, including intermittent generation, always lowers the probability that the system will have to import capacity or curtail loads by some amount. The ELCC metric quantifies how much this probability is reduced, and thus indicates the extent to which the resource helps the utility meet its load, including its peak load.

Q. Is the concept of capacity value that underlies the ELCC different from the concept of capacity value that underlies the exceedance method?

A. Yes. The exceedance method only attempts to measure capacity deliveries during the highest load hours. The ELCC method measures capacity deliveries during the highest load hours and all other hours when the utility is capacity deficient.

Q. Is one or the other concept of capacity value more consistent with utility planning for generating resources?

A. Both capacity metrics are used in utility planning analyses. Utilities generally plan and make resource additions in order to have sufficient generating capacity during peak loads. However when comparing the reliability of various planning portfolios, utilities compare the portfolio's annual ENS and LOLP in order to determine which portfolios best meet system capacity requirements.

Q. Do you believe that the Commission needs to make an absolute determination of the methodology in this docket?

A. No, but if the Commission is going to make capacity value a central determinant of the avoided cost price, the Commission should at minimum require the next utility IRPs to perform comparative ELCC and exceedance method calculations and incorporate both concepts into the proposed "capacity contribution factor."

Q. Is there Commission precedent for this approach?

A. Yes. In UM 1559, the Commission ordered the utilities to use a range of methodologies to evaluate solar resource value, including the ELCC. OPUC Order No. 12-396, at 4-5.

Q. How often should capacity value be reevaluated?

A. Regardless of the methodology used, capacity values for resource classes change over time. The changing diversity of a resource class and the correlation between resource generation and load can make significant changes to the resultant capacity value calculation. At minimum, each IRP will need to have a robust, resource-specific capacity value determination if capacity contribution is to be a central determinant of the avoided cost.

BALANCE WITH OTHER PORTFOLIO VALUES NOT PRESENTLY CAPTURED

Q. Is capacity value the only significant, generalizable portfolio value difference identified between renewable QFs and the gas proxy resource?

A. No. Counteracting the proxy resource's capacity value advantage are several supply value advantages of renewable QFs. Though presently unquantified, they are identified in several parties' testimony. For example, avoided cost rates do not presently account for the cost of new natural gas transportation infrastructure, which is a significant and growing element of the marginal cost of new gas plants. CREA/200/Reading/23-25; OneEnergy/100/Eddie/22-30. Nor are the cost risks of the gas proxy's exposure to fuel price volatility quantified. I recommend that the Commission keep these presently unquantified differences in supply value in mind as it considers whether a capacity value adjustment is necessary to achieve an appropriate standard avoided cost.

Q. Have parties identified a supply value advantage that QFs have over both the proxy gas resource and the proxy renewable resource?

A. Yes. Parties explained that QFs offer incremental capacity additions that avoid the "lumpiness" characteristic of the large, utility scale resource additions represented by both the gas and the renewable proxy. CREA/200/Reading/25-28; OneEnergy/100/Eddie/12-15. The investment deferral or peak reducing value of incremental additions has been recognized in the energy efficiency context and is also applicable for QF resource additions. *Id.*

Q. Have parties proposed methodologies for adjustments to address the supply value differences that you discuss?

A. OneEnergy points out several directions for methodologies that the Commission could direct utilities to use to quantify and capture these significant values. OneEnergy/100/Eddie/15, 29-30. I agree that OneEnergy has identified some promising directions for analyzing and quantifying these values.

Q. Are there alternative ways for the Commission to incorporate these values into the avoided cost?

A. Yes. Although I support improving the methodologies for quantifying these values with respect to renewable resources, the Commission has recognized in the past that not every cost and value needs to be precisely quantified in order to achieve an appropriately balanced avoided cost. By following Staff's recommendation in this case, the Commission would be quantifying values advantageous to the proxy resource without quantifying other values on which QFs present a cost advantage. To achieve a better balance without requiring significant additional analysis and quantification, the Commission could adopt implementation changes other than direct rate adjustments to recognize these QF values. I recommend that the Commission approve longer contract terms (*see* CREA/100/Hilderbrand/30; CREA/200/Reading/35; REC/200/Schoenbeck/22, 25; OneEnergy/100/Eddie/37-38) and allow for levelized rates, at least in some instances (*see* CREA/200/Reading/9-12; OneEnergy/100/Eddie/39).

Q. Why would increasing the fixed rate contract period be a reasonable response to adjusting for capacity value?

A. Staff's proposal to adjust for capacity value, particularly absent adjustment for these other QF values, resolves any asserted "mismatch" between QF rates and supply value—if not creating a mismatch in the other direction. *See* Staff/100/Bless/16-17. The Commission's objective in setting the 15-year fixed/5-year variable standard contract length was to balance QFs' ability to secure financing with the likelihood of getting the price right over the fixed-rate period. REC/200/Schoenbeck/22. If the avoided cost rate is right—or actually tilted in the direction of the proxy resource—then locking in that rate for a longer period of time should be more attractive. This is particularly true at a time, like the present, when there is more upside risk than downside risk associated with deviation from current natural gas forecasts.

Q. Given your view, what contract length would you recommend?

A. I agree with many intervenors that a fixed rate contract period of at least 20 years would be appropriate. *See* CREA/100/Hilderbrand/30; CREA/200/Reading/35; REC/200/Schoenbeck/25.

Q. Why would levelized rates be an appropriate way to account for the value of QFs allowing utilities to defer "lumpy" capacity additions?

A. Lengthy sufficiency periods are when QF additions can do most allow utilities to defer the next generating resource addition. However, QF development will be limited during that very same period because the early year rates would make financing difficult. CREA/200/Reading/9-10; OneEnergy/100/Eddie/39. An appropriate way to correct this situation, and help realize the value of incremental capacity additions during lengthy sufficiency periods, would be to give QFs the option of levelized rates. If the Commission wished to make levelization available on a more limited basis, it could require levelized rates to be offered only when the sufficiency period exceeded three to five years, or some other defined number.

Q. Does the proposed capacity value adjustment also improve the rationale for a levelized price option?

A. Yes. If rates are adjusted for capacity value, resources with lower capacity values would be paid primarily for their energy value. This reduces the difference between sufficiency and deficiency rates because the capacity payments associated with the deficiency period are reduced. Specifically, variable energy resources with less significant capacity values will have a small spread between deficiency rates and sufficiency rates, making levelization a less significant impact to the utility. If the Commission adjusts avoided costs to reflect capacity value, the effect of levelization would be materially different from the last time the Commission considered levelized rates in UM 1129.

INTEGRATION COSTS FOR QF RESOURCES

Q. You addressed the process for setting integration costs in your prior testimony. To be clear, do you agree that wind integration costs should be accounted for in QF avoided cost rates?

A. I tend to agree with parties who have suggested that wind resources in diverse wind regimes (ODOE/100/Carver/9-10) and in smaller capacity increments

(CREA/200/Reading/9-12) may impose a lesser reserve requirement, and therefore lower integration costs, than the resources used as foundational inputs to the utility wind integration studies. Reducing or eliminating wind integration adjustments based on size and diversity could be reasonable. However, my primary objective is to ensure that integration studies themselves be cost-based and rational, so that the standard adjustment for integration costs is fair.

Q. Did any other intervenor address the process for how the amount of a utility's wind integration cost adjustment would be determined?

A. Oregon Department of Energy's testimony recommended that the Commission hold periodic evidentiary proceedings to determine the amount of the integration cost adjustments. ODOE/100/Carver/10.

Q. Do you agree that an evidentiary proceeding is appropriate to set the integration cost adjustment?

A. I agree that an evidentiary proceeding should be available to a party who can persuade the Commission to suspend an avoided cost tariff filing because of a sufficiently inaccurate integration cost. However, I continue to believe that, with improved scrutiny and better-defined procedures, utility IRP reviews can be the most suitable place to scrutinize and resolve any concerns with integration studies.

Q. What improvements are needed to the IRP review to make it a suitable venue for determining QF wind integration cost adjustments?

A. RNP has previously understood the Commission Staff to view detailed criticism of utility wind integration studies as inappropriate for an IRP, except when changing the integration assumptions would alter the utility's preferred portfolio selection. In other words, Staff has viewed Commission review of an IRP as an exercise to acknowledge or not acknowledge the preferred portfolio, but not to approve or disapprove of constituent parts of the model. If this remains the threshold for considering integration studies in IRPs, then a level of scrutiny appropriate to assigning fair integration cost adjustments for QFs may not result. Moreover, wind integration studies have been presented with IRP Updates, with little process and limited clarity about the consequences of Commission review. I recommend that, if IRPs are where the Commission will set the QF integration cost adjustments, the Commission should be clear that its acknowledgment orders will specifically approve or disapprove integration costs and, where disapproved, will direct adjustments before costs can be assigned to QFs.

Q. Do you agree that QFs should be able to procure within-hour integration services from another provider as an alternative to accepting the standard wind integration deduction from the avoided cost rate?

A. Yes. I agree that if a QF commits to self-supply wind integration services, it should not be charged the utility's wind integration cost. *See* CREA/200/Reading/16-17. This may occur because the QF is located in another balancing authority and paying that provider's established rate for balancing services. Or it may be because an on-system QF has contracted to purchase balancing services from another provider. The wind integration deduction from the standard rate (and, during the sufficiency period, from the renewable avoided cost rate) for wind QFs should be based on whether the variable QF brings within-hour balancing services with it, not simply on where the QF is located (as Staff's testimony appears to propose, at Staff/100/Bless/27). For example, NorthWestern Energy's Montana QF-1 tariff gives QFs the option to self-supply within-hour integration services or purchase them from the utility as a deduction from the total monthly avoided cost payment.[2]

PROXY RESOURCE TRANSMISSION COSTS

Q. Do you agree that transmission costs associated with the proxy resource should be included as part of the avoided cost?

A. I agree that, whenever transmission costs are an element of the IRP modeling of the proxy resource, they should be included in calculation of the avoided cost rate. *See* CREA/200/Reading/17-20; CREA/300/Svendsen/14-15; OneEnergy/100/Eddie/22, 31-32. Staff's testimony appears to suggest that transmission costs should be included as part of the proxy resource's cost only if the proxy resource is "off-system"—*i.e.*, the resource is in another balancing authority ("BA") and the utility would be paying that BA's transmission rates. *See* Staff/100/Bless/6, 29. However, that is not the only circumstance in which the proxy resource's modeled cost is fundamentally influenced by the cost of transmission. For example, PacifiCorp's renewable avoided cost, the proxy is

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[2] NorthWestern Energy's Schedule No. QF-1, 2nd Revised Sheet No. 74.6 (available at http://psc.mt.gov/Docs/ElectronicDocuments/pdfFiles/D2012-1-3IN13011054131TA.PDF) specifically states:

> "Wind Integration: Sellers of Wind Energy selecting Options 1 or 2 must contractually agree to the provision of wind integration services for the term of the Agreement and may either self-supply sufficient within-hour regulating reserves under terms acceptable to NorthWestern or pay the Utility for these services according to the Wind Integration Tariff (WI-1). Payment to the Utility for selection of service through WI-1 will result in a deduction from the total monthly payment made to the QF to reflect the provision of integration services."

based on a long-range, low cost, high capacity factor wind resource whose development depends not upon paying another BA's transmission rates, but on successful expansion of PacifiCorp's own transmission system. Those costs are part of the IRP modeling. In a situation like that, I agree with CREA and OneEnergy that transmission costs for an on-system resource should be included in the proxy resource cost. CREA/300/Svendsen/14; OneEnergy/100/Eddie/19.

ADJUSTMENT FOR AVOIDED LINE LOSSES

Q. Do you agree with the testimony at OneEnergy/100/Eddie/35-36 that rates for certain QFs should be adjusted to reflect avoided line losses?

A. I agree that QF rates should be adjusted to reflect avoided line losses in certain circumstances. Line losses are a cost associated with large-scale generation that is already well-documented by utilities and should be compensated where avoided by QFs. Although line loss savings can vary by project, OneEnergy has presented a reasonable, conservative approach to making a generalized adjustment to avoided cost rates.

Q. Do you agree that line loss adjustments should be limited to certain QFs?

A. I appreciate OneEnergy's effort to create a bright line to simplify implementation of a line loss adjustment, and I do not object to the limitation that OneEnergy proposes (3 MW, connected at distribution voltage). For PURPA published rates, I particularly agree with limiting line loss adjustments to QFs that connect to the utility system at distribution voltages. Although QFs connecting to the transmission system closer to load centers than the proxy may have transmission system line loss advantages, it would be difficult to say that this benefit exists in most to all cases. It is much easier to assume that most or all QFs connected at distribution voltage achieve transmission system line loss savings over the proxy.

Q. Do you agree that a size limitation on line loss adjustments is also needed?

A. Not in this case. The question is whether savings are still achieved if a particular QF generates more than the local load demands, thus offsetting transmission line losses by placing additional demands on the distribution system. OneEnergy appears to have selected 3 MW as a size at which that circumstance is unlikely to occur. I think it would be reasonable to make the recommended line loss adder available to any QF connected at distribution voltage whose peak generating capability is less than the peak load at the substation to which it will connect. Even still, I do not believe that any size limitation is necessary for a reasonably accurate aggregate adjustment, given that the adder is proposed to reflect only *transmission system* line loss savings.

Q. Do you agree with OneEnergy's proposal to limit the line loss adjustment to only transmission system line loss savings?

A. For purposes of QF rate adjustments, I do agree. If the adjustment pertained solely to distributed, rooftop solar systems, I would recommend use of *at least* average line loss savings for both the transmission and distribution systems (and likely something more granular, as I recommended in UM 1559). But, as I stated above, it is reasonable to be more conservative when making a generalized adjustment for most or all QFs connecting at the distribution level.

OneEnergy's 3.9% number is a solid estimate of average transmission system line losses for PacifiCorp's system derived from the company's own filings. Because PGE's average losses reported in UM 1559 were lower and Idaho Power's higher, different numbers may be appropriate for those utilities if they can present information that segregates their transmission system losses from their total average line loss estimates. Otherwise, I agree that a generalized 3.9% adjustment for QFs connected at distribution voltage would be appropriate.

DEFINITION OF RECs/ENVIRONMENTAL ATTRIBUTES

Q. For QFs electing the renewable avoided cost stream, RECs pass to the utility during the deficiency period. Some testimony has addressed how those RECs should be defined. Do you have a reaction to that testimony?

A. I assume that legal briefing will cover the specific details of the REC definition. From a policy perspective, I agree with two themes raised in other parties' testimony. First, I agree that what QFs pass to the utilities during the deficiency period must include every attribute or element necessary for the utility to retire the conveyed instrument for Oregon RPS compliance. *See* Staff/100/Bless/17. Thus, the definition must be consistent with how the Oregon Department of Energy ("ODOE") has defined a REC for Oregon RPS purposes.

Second, I concur that there is industry consensus that the non-power attributes contained within a REC, which is issued for generation of electricity from a renewable resource, do not include the separate value associated with the capture and destruction of greenhouse gases ("GHGs"). In other words, a facility may (1) prevent GHGs from reaching the atmosphere, for which the facility may receive an offset; *and* (2) generate electricity from those captured GHGs, thereby displacing GHGs that would have been released by other electricity generation and earning the facility a REC. *See* CREA/300/Svendsen/7-9. I note that the Washington Legislature recently adopted HB 1154 (by unanimous vote of both the House and Senate) to clarify that its RPS definition of nonpower attributes does not include values associated with on-site capture and destruction of GHGs. The ODOE definition of REC does not specifically distinguish between these two elements, but ODOE's testimony in this case makes clear that it interprets its definition to be consistent with the WREGIS definition, which does expressly distinguish between direct GHG reductions and avoided electricity emissions. ODOE/100/Carver/11-12. The standard QF contract should include a statement to the effect that the REC passed to the utility does not include any claims or benefits associated with on-site capture and destruction of GHGs.

PARTIAL STIPULATION REFINEMENT

Q. Did Staff or intervenor testimony identify a need to depart from the existing "partial stipulation" approach to disaggregation?

A. Several parties recognized the importance of addressing disaggregation effectively, but did not identify a need to significantly modify the existing Oregon partial stipulation approach to do so. *See* Staff/100/Bless/38; CREA/100/Hilderbrand/13-16. OneEnergy supported PacifiCorp's concept for clarifying and limiting the allowance of common passive investors in projects within five miles of one another (OneEnergy/100/Eddie/8) and CREA explained why retaining the ability to use passive investors is important to project finance models for locally owned community projects (CREA/100/Hiderbrand/14-15). Although I continue to believe that the partial stipulation has worked effectively in its current form, RNP is open to a refinement of the passive investor allowance that will tighten the policy but continue to enable communities to invest in clean generation. Ongoing discussions among various parties to this docket regarding how to refine the common passive investor allowance are likely to result in a reasonable and effective refinement of the partial stipulation.

CONCLUSION

Q. Please summarize your reply testimony.

A. Staff has proposed to make a major adjustment to avoided cost rate setting by incorporating a resource capacity value adjustment. I agree that the Commission should maintain the 10 MW threshold, but do not recommend that the Commission adopt Staff's adjustment concept unless it uses a broader definition of capacity value and balances the adjustment with attention to other, presently unquantified supply value advantages of QFs. In addition, I recommend a deliberate approach to setting integration rates for QFs; inclusion of transmission costs in the proxy whenever they are modeled in the IRP; compensation for avoided line losses for certain QFs; express language regarding the exclusion of on-site GHG capture attributes; and a narrow refinement to the five-mile partial stipulation.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I served the foregoing REPLY TESTIMONY OF JIMMY LINDSAY upon the following parties on the service list, via electronic mail, on April 29, 2013:

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